Renewable and Sustainable Energy Reviews 30 (2014) 170–183

Contents lists available at ScienceDirect

Renewable and Sustainable Energy Reviews

journal homepage: www.elsevier.com/locate/rser

Reviewing electricity production cost assessments

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ARTICLE INFO

Article history:
Received 1 March 2013
Received in revised form
11 September 2013
Accepted 26 September 2013
Available online 25 October 2013

Keywords:
Electricity generation costs
Levelized costs
Energy market analysis
Cost comparisons
Policy implications

ABSTRACT

A thorough review of twelve recent studies of production costs from different power generating technologies was conducted and a wide range in cost estimates was found. The reviewed studies show differences in their methodologies and assumptions, making the stated cost figures not directly comparable and unsuitable to be generalized to represent the costs for entire technologies. Moreover, current levelized costs of electricity methodologies focus only on the producer's costs, while additional costs viewed from a consumer perspective and on external costs with impact on society should be included if these results are to be used for planning. Although this type of electricity production cost assessments can be useful, the habit of generalizing electricity production cost figures for entire technologies is problematic. Cost escalations tend to occur rapidly with time, the impact of economies of scale is significant, costs are in many cases site-specific, and country-specific circumstances affect production costs. Assumptions on the cost-influencing factors such as discount rates, fuel prices and heat credits fluctuate considerably and have a significant impact on production cost results. Electricity production costs assessments similar to the studies reviewed in this work disregard many important cost factors, making them inadequate for decision and policy making, and should only be used to provide rough ballpark estimates with respect to a given system boundary. Caution when using electricity production cost estimates are recommended, and further studies investigating cost under different circumstances, both for producers and society as a whole are called for. Also, policy makers should be aware of the potentially widely different results coming from electricity production cost estimates under different assumptions.

Contents

Abbreviations: CASES, cost assessments for sustainable energy systems; CC, coal condensing; CCGT, combined cycle gas turbine; CHP, combined heat and power; CHP-B, combined heat and power biomass; CHP-W, combined heat and power waste; DECC, Department of Energy and Climate Change; DR, discount rate; EIA, U.S. Energy Information Administration; EU, European Union; EUR, Euro; EUSUSTEL, European Sustainable Electricity; EWEA, European Wind Energy Association; GBP, British Pound; GDP, Gross Domestic Product; HC, heat credit; HP, hydropower; IDC, interest during construction; IEA, International Energy Agency; IHS, Information Handling Services; IMF, International Monetary Fund; kW_e, kiloWatt electrical; MIT, Massachusetts Institute of Technology; MW_e, megaWatt electrical; MWh_e, megaWatt-hour electrical; NEA, Nuclear Energy Agency; NEEDS, New Energy Externalities Development for Sustainability; NP, Nuclear Power; OCGT, open cycle gas turbine; PB, Parsons Brinckerhoff; PV, Photovoltaics; PwC, PricewaterhouseCoopers; PWR, pressurized water reactor; R&D, research and development; SKGS, Skogen, Kemin, Gruvorna och Stålet (Swedish); USD, United States Dollar; VGB, VGB PowerTech e.V.; WP, Wind power

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1364-0321/$ - see front matter
http://dx.doi.org/10.1016/j.rser.2013.09.028

1. Introduction

The last decade has witnessed an increased number of studies examining electricity generation or production costs[1] from alternative power generating technologies, and references to such studies can often be heard in the public debate. In the European Union (EU), electricity production costs assessments have been used to justify various forms of economic support schemes for renewable power generating technologies [1,2], and to estimate necessary levels of CO_2 emission fees, such as those used within the EU Emission Trading System, needed to narrow the gap between fossil fueled technologies and other low-carbon alternatives [3]. Recent literature in this field includes the works by NEEDS [4], IEA and NEA [5], EIA [6], VGB [7], Elforsk [8], and DECC [9].

It is common to find the cost figures reported in these studies to vary greatly. This is problematic since electricity generation cost assessments are typically used to rank different power generating technologies based on the expected generation cost and to estimate economic subsidies or penalty charges needed. As such, generation cost assessments are important in energy decision and policy making.

This paper focuses on costs for producers, i.e. costs that that can be directly attributed to the investment and operation of power plants. Such costs will be named *production costs of electricity* in this paper. However, power plants also cause socio-environmental damages during their construction, operation and dismantling, for instance, due to the emission of environmentally unfriendly and hazardous gases, particles and greenhouse gases. Such costs are called *external costs*, since they are costs not incurred by the power plant owners.[2] External costs are discussed in this paper, but in a more qualitative way. Whenever they are discussed and/or added to production costs, the wording *electricity generation costs* will be used.

This paper[3] reviews several electricity production cost assessments with the purpose to identify the differences in the methodologies and in the underlying assumptions that can explain the often diverging cost figures reported in the literature. These differences are discussed with special attention to some major factors influencing the stated electricity production costs. Moreover, issues regarding the current methodologies are also highlighted and discussed from a perspective of energy policy making.

A thorough analysis of twelve studies of electricity production costs published in the year 2007 or later, is carried out. Some of these studies were conducted or commissioned by government departments [10–12]; others were performed by energy agencies [5], by research and development companies [8], consulting firms [13], and by European Commission funded projects [4,14,15]. The study by Förnybart.nu [16] is a compilation of different studies [17–20] and was also analyzed in this study. A recent review by Branker et al. [21] about solar photovoltaic levelized cost of electricity production was also included.

The review about low-carbon baseload generating technologies by Nicholson et al. [22] was not considered since the electricity production costs presented appear too generalized and it was not deemed possible to distinguish different cost components (for example, external costs are not separated from electricity production costs and the discount rates used are not presented). Freeman [23] provided an overview of the environmental costs of electricity, while Damen et al. [24] compared electricity and hydrogen production systems with CO_2 capture and storage, but none of them are included since they appear quite outdated. Finally, we remark that Khatib [25] provided an overview of the joint report by the IEA and the OECD Nuclear Energy Agency [5], which is one of the 12 studies included in our review.

The paper is structured as follows: Section 2 presents an overview of the electricity production cost estimates from different studies. Section 3 highlights some factors that have a major influence on the stated costs, and which can explain the wide range of published estimates. Section 4 is devoted to the implications of using these electricity production cost estimates for policy making. Finally, Section 5 provides a concluding discussion of the main findings.

2. Overview of current electricity production cost estimates

The main focus of this study is on current cost figures of commercial power generating technologies: to avoid outdated cost figures, no study published earlier than the year 2007 was included in this review (see Table 1).

External costs, due to the potential impact of power plants on, for example, human health, ecosystems, crops, buildings and climate change are not considered. Costs induced by taxes and subsidies are also excluded, despite the fact that such costs can be significant, since they vary among different countries and are decided by governments. However, external costs, subsidies, taxes and differences in technical characteristics have to be considered in decision and policy making. The electricity system is simply affected in different ways depending on the technology with some power plants in more need of balancing power, back-up capacity and transmission investments than others. Therefore, these will be discussed in Section 4 which considers the policy implications of assessments for electricity generation costs. Estimates of future electricity production costs that might change in the future due to, for example, learning curves are also outside the scope of this review.

From an investor's perspective, the future assumptions about the income coming from produced electricity are crucial for investment decisions. In liberalized electricity markets, investors face greater risk as future electricity price levels are uncertain [26]. Moreover, current electricity production cost methodologies generally fail to account for the fact that dispatchable power generating technologies have an economic and technical advantage over non-dispatchable alternatives, since the latter only produce electrical energy during favorable weather conditions. However, our

[1] A more suitable name would be *electrical energy* production or generation costs. The use of *electricity* as an equivalent of electrical energy is commonly accepted and it will therefore be retained in this paper.

[2] See the report by the European Commission [28] for more details.

[3] This paper is based on the work conducted by Larsson [29] on behalf of the Energy Committee at the Royal Swedish Academy of Sciences. For details and further information related to the topics discussed in this paper, please see Larsson [29].

Table 1
Reviewed studies and investigated power generating technologies. Consulting firms ARUP [10] and Parsons Brinckerhoff [12] conducted the latest U.K. Department of Energy and Climate Change (DECC) studies on electricity production costs. The SKGS study (cooperation between Swedish industry associations) on electricity production costs was performed by the professional services firm PricewaterhouseCoopers (PwC) [13]. All abbreviations are listed in the nomenclature. Some studies have more than 1 year in the references since they were divided in several different papers and/or because the information is located at several different places.

Study	**Included power generating technologies**										
	CC	CHP-B	CHP-W	HP	CCGT	CCGT-CHP	OCGT	PV	NP	WP on	WP off
CASES [14]	x	x		x	x	X	x	x	x	x	x
Elforsk [8]	x	x	x	x	x	X		x	x	x	x
EUSUSTEL [15]	x			x	x	X		x	x	x	x
Förnybart.nu [16]		x						x	x	x	x
IEA and NEA [5]	x				x	X		x	x	x	x
NEEDS [4]	x	x			x		x	x	x		x
SKGS [13]				x					x	x	
DECC [9]	x	x	x	x	x	X	x	x	x	x	x
EWEA [18]										x	x
EIA [11]	x			x	x		x	x	x	x	x
VGB [7]	x			x	x		x	x	x	x	x
Branker et al. [21]								x			

assessments attempt to only consider studies of production costs. The only exceptions to this rule are represented by some studies which incorporate the costs of carbon dioxide emission fees and backup costs for intermittent power generating technologies into the "*normal*" electricity production costs. Given that these costs were not presented as external cost factors or taxes, we opted to keep them to avoid complicating the comparison with the other reviewed studies (see Sections 3.6 and 3.7).

Costs are presented in United States Dollar (USD). Exchange rates used for conversions from other currencies are presented in Table 2. Cost figures originating in foregoing years were recalculated to 2011 values by using the (country specific) GDP deflators provided by the IMF [27]. Note that many of the reviewed studies use other currencies than USD, so that the presented cost figures could be sensitive to changes in exchange rates.

Levelized costs of electricity production for non-renewable power generating technologies are shown in Fig. 1, wind power and combined heat and power biomass-fired plants in Fig. 2 and hydropower and photovoltaics in Fig. 3.

Figs. 1–3 show that the estimated producer costs vary quite considerably between different studies. Moreover, the dispersion of the estimates for hydropower and photovoltaics is much higher than that of the other technologies. This is due to a few extreme hydropower cost figures, together with the fact that electricity production costs for hydropower and photovoltaics tend to be highly site-specific. In this context it should be mentioned that the stated production costs are neither directly comparable with each other, nor can they be generalized to represent a general electricity production cost for a specific power-generating technology, due to the methodological differences and the varying assumptions present in the reviewed studies.

As can be seen in the previous figures, the stated electricity production costs are sensitive to changes in the discount rate (DR), i.e. the interest rate used to determine the present value of future cash flows. Power generating technologies associated with high upfront capital costs are very sensitive to changes in discount rate, as it reflects the value put on time preferences. High upfront costs have to be valued against a stream of discounted future incomes. For example, a payment of 1000 $ occurring 10 years from now is worth 613 $ today at a discount rate of 5%, and 386 $ at a discount rate of 10%. As such, the value that is chosen for the discount rate can "*weight*" the decision towards one option or another. Moreover, electricity production costs from combined heat and power (CHP) plants are strongly influenced by assumptions on heat credits (HC), i.e. the value of the heat that is produced jointly with electrical energy.

Assumptions on discount rates and the methodology used to calculate heat credits vary significantly across the studies, thereby

Table 2
Assumed exchange rates when original costs were not presented in USD. Current data obtained from Federal Reserve.

Currency	**Exchange rates used**
EUR	1.393 USD/EUR
GBP	1.604 USD/GBP
SEK	0.154 USD/SEK

contributing to the large dispersion of costs. The diverging assumptions about the fuel price are the main reason for the different cost estimates for CHP-B, CHP-W, CCGT-CHP, and lignite-fueled power plant production costs. For most power generating technologies (with the exception of fossil-fueled alternatives), the assumptions on investment costs differ significantly and contribute to additional variability in the final estimates. Another reason for discrepancies across studies is the assumption about the mode of operation for a power plant. For example, dispatchable power plants are in some studies assumed to be used in a base load mode, in other studies in intermediate or in peak load modes.

Electricity productions costs are also dependent on the location of the power plant. This is visualized by Figs. 4 and 5 which show that electricity production costs indeed seem to vary between different world regions. Differences in e.g. investment costs, fuel prices and labor costs results in different preconditions and thereby different electricity generation costs for different world regions [5], as Figs. 4 and 5 indicate. Table 3 presents the reviewed studies geographical coverage (location) and their method of computation. Production costs presented in Elforsk [8] and other reviewed studies also show a strong influence of economies of scale, meaning that production costs are largely determined by the installed capacity, i.e. plant size.

The cost-influencing factors mentioned are just examples of why studies differ. Some factors will be more thoroughly discussed in Section 3, while others will not be dealt with mainly due to lack of transparency (i.e. lack of sufficient information, lumped cost figures, unknown impacts, etc.) in the reviewed studies. Production costs for waste-fueled combined heat and power plants (CHP-W) are not shown in Figs. 1–3. The reason is that such production costs can in fact be negative, since these power plants are usually paid for accepting waste for burning. This makes it difficult to exhibit CHP-W production costs together with production costs from other power-generating alternatives. Interested readers are referred to Larsson [29] for more details.

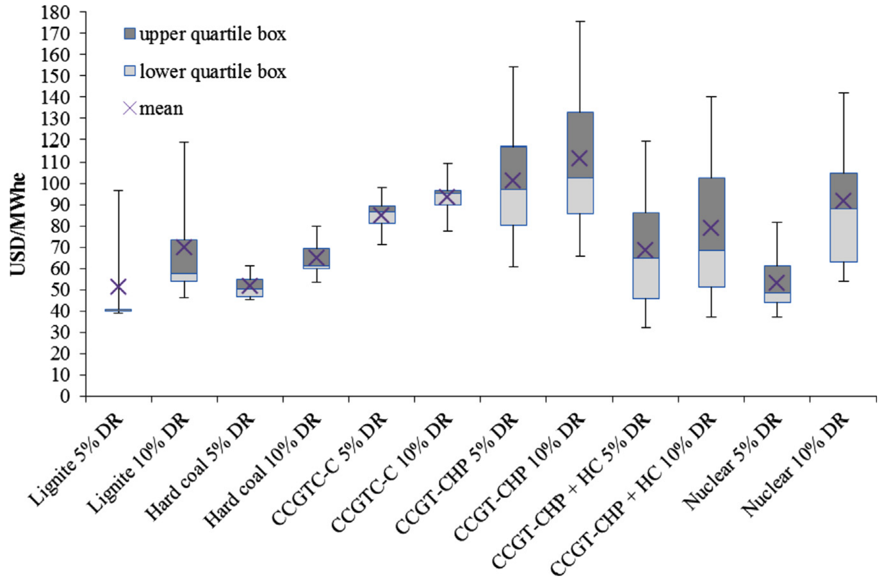


Fig. 1. Levelized costs of electricity production for non-renewable power generating technologies. The cost figures are visualized in box plots showing the minimum value, lower quartile, median, upper quartile, and the highest value. The mean value is also included in the figure. Costs induced by assumptions on carbon dioxide emission fees (Section 3.6) are not included. Studies that do not present electricity production costs by using a 5% or a 10% discount rate are not included in this figure (i.e. [5,7,8,12,14–16]).

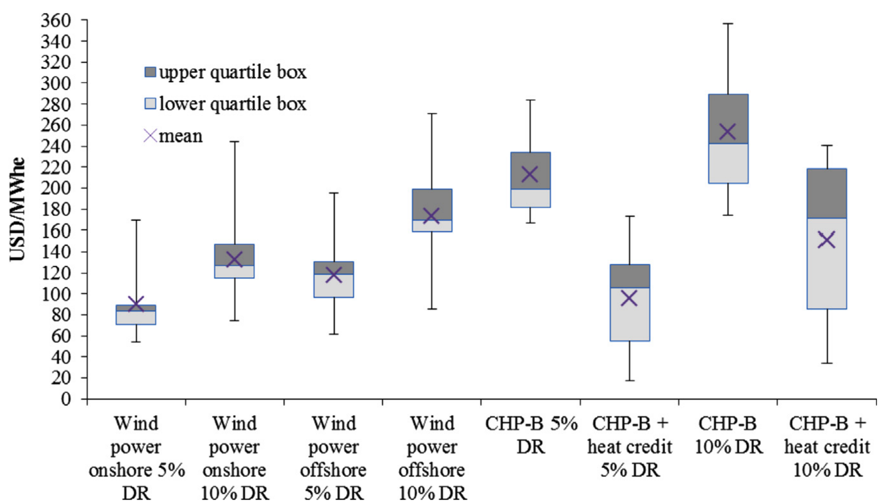


Fig. 2. Levelized costs of electricity production for wind power and combined heat and power biomass-fired plants. The cost figures are visualized in box plots showing the minimum value, lower quartile, median, upper quartile, and the highest value. The mean value is also included in the figure. Costs induced by assumptions on backup costs for intermittent power generating technologies (Section 3.7) are not included. Studies that do not present electricity production costs by using a 5% or a 10% discount rate are not included in this figure (i.e. [4,5,7,8,10,14,15]).

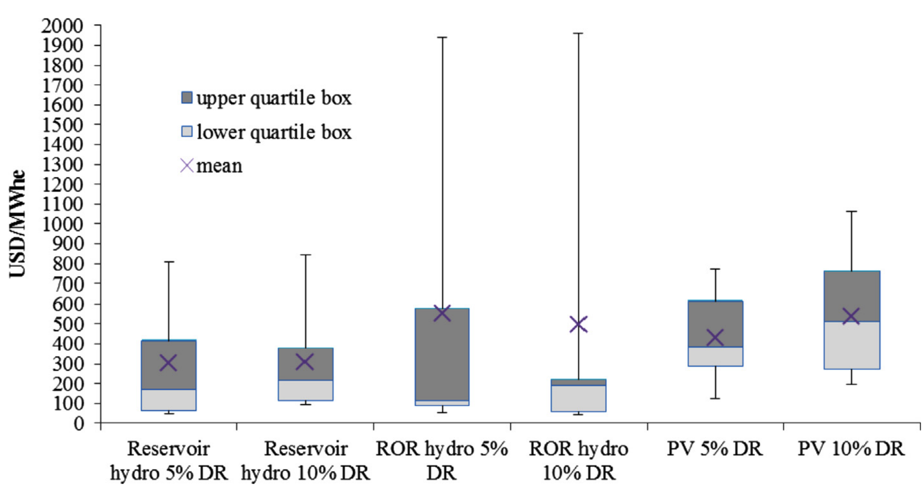


Fig. 3. Levelized costs of electricity production from hydropower and photovoltaics. The cost figures are visualized in box plots showing the minimum value, lower quartile, median, upper quartile, and the highest value. The mean value is also included in the figure. Costs induced by assumptions on backup costs for intermittent power generating technologies are not included. Studies that do not present electricity production costs by using a 5% or a 10% discount rate are not included in this figure (i.e. [4,5,7,8,10,14,15,20]).

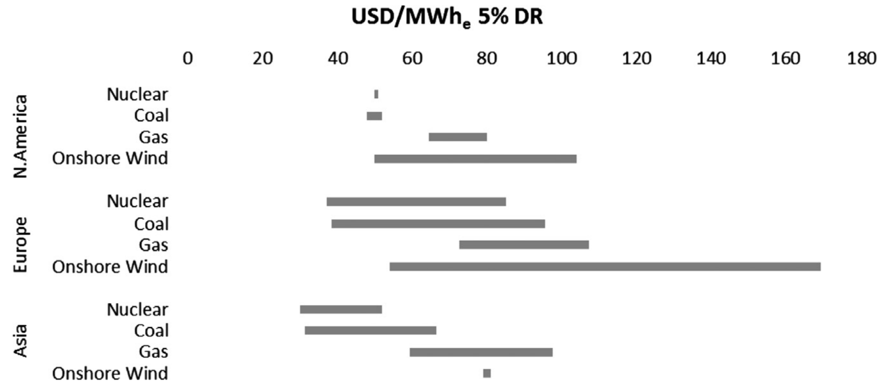


Fig. 4. Comparison of levelized costs of electricity production in different world regions at 5% discount rate. Only a small subset of studies provided regional data (i.e. [4,5,8,14,15]).

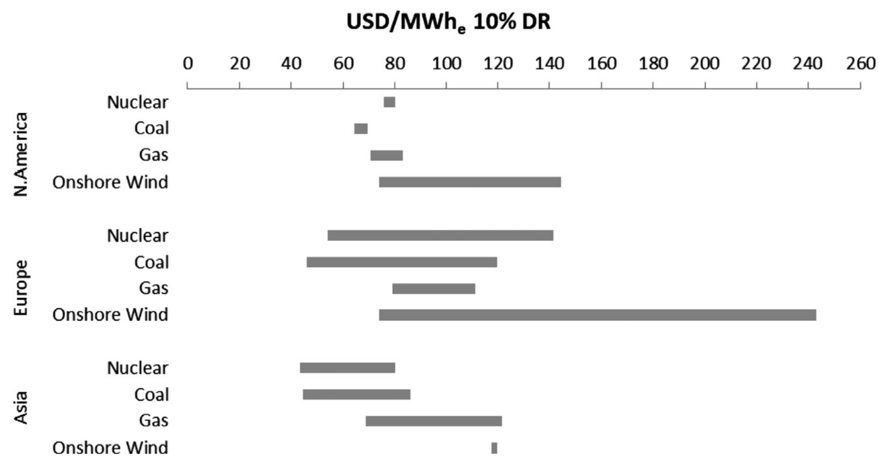


Fig. 5. Comparison of levelized costs of electricity production in different world regions at 10% discount rate. Only a smaller subset of the reviewed studied provided regional data (i.e. [5,7,8,10,12,14,15]).

Table 3
Geographical coverage and method of computation.

Study	Geographic location	Method of computation
CASES [14]	Europe	Average lifetime levelised generating cost
Elforsk [8]	Sweden (Europe)	Equivalent annual cost
EUSUSTEL [15]	Europe	Average lifetime levelised generating cost
Förnybart.nu [16]	Sweden (Global)	Literature review
IEA and NEA [5]	Europe (Global)	Levelised costs of electricity
NEEDS [4]	Europe	Average lifetime levelised generating cost
SKGS [13]	Sweden (Europe)	Free cash flow
DECC [9]	United Kingdom	Levelised cost of generation
EWEA [18]	Europe	Levelised cost
EIA [11]	United States	Levelized cost
VGB [7]	Europe	Levelised costs of electricity
Branker et al. [21]	Global	Levelized cost of electricity

3. Main reasons for diverging electricity production cost estimates

3.1. Methodological differences in the computation of the levelized cost of electricity

The cost of generating electricity can be calculated in various ways. A widely accepted approach is the so called *levelized cost of electricity* (LCOE), or similar names such as *average lifetime levelised generation cost* (ALLGC), and *levelised cost of generation* (LCG). IEA and NEA [5], DECC [9], CASES [14], NEEDS [4] and EUSUSTEL [15] all used definitions of levelized cost of electricity similar to the formula presented below in Eq. (1). Despite this, differences in methodology exist, and they are in some cases substantially enough to cause significant differences in results between studies.

$$\mathrm{LCOE} = \frac{\sum_t (\mathrm{investment}_t + O\&M_t + \mathrm{Fuel}_t + \mathrm{Others}_t)(1+d)^{-t}}{\sum_t (\mathrm{Electricity}_t (1+d)^{-t})} \quad (1)$$

Levelized cost of electricity formula. Expenditures for carbon dioxide emissions, decommissioning, refurbishment, etc. are captured in the

parameter "Others". Which assumptions are included as well as what they are, vary from study to study. A derivation of Eq. (1) can be located in [5]. Observe that the carbon costs and the decommissioning costs mentioned in [5] is lumped under the "Others" category in Eq. (1).

Investment_t	Investment expenditure in year t
$\text{O\&M}_t$	Operation and maintenance expenditure in year t
Fuel_t	Fuel expenditure in year t
Others_t	Other expenditures in year t
Electricity_t	Electrical energy generation in year t
d	Discount rate

Eq. (1) simply follows from the basic assumption that the present value of all discounted power-plant revenues has to be equal to the present value of all discounted power-plant costs. The LCOE is thereby equal to the constant average price at which electricity must be sold to reach breakeven over the economic lifetime of the power plant project.[4] External costs, taxes and other costs not directly connected with a power plant (as part of its construction or operation), might also be included in the LCOE. However, these costs were not considered in the present study (see the previous discussion in Section 2).

A completely different valuation approach compared with the standard formula-based approaches to calculate the LCOE is found in the analysis by EIA [11]. In their analysis, production costs are calculated using an energy-economic model, whose results cannot be exactly recreated outside the model [30]. Even though the production costs are presented as levelized costs, the underlying approach is quite different from the formula-based methodologies such as the LCOE (Eq. (1)).

Elforsk [8] and VGB [7] used the equivalent annual-cost method to calculate the investment-costs share of the total production cost, while cost components such as operation and maintenance (O&M) and fuel costs are assumed to be constant over time. In other cases production costs are calculated with confidential free cash flow models [13] or more or less unclear approaches [17,19].

The expression *levelized costs* can be confusing, since such a commonly used terminology might imply that production costs are calculated using the same methodology, while this is not necessarily the case. A levelized cost is nothing else than a mathematical conversion of variable annual costs into a stream of constant payments, with the same present value as the total cost incurred by a power plant over its operating life. The result, in the case of electricity producing projects, is a cost per unit of electricity produced. This cost is equal to the minimum average price at which electricity must be sold to reach breakeven, which means that all studies presenting such production cost figures by definition presents levelized costs. Taxes and subsidies can be accounted for in the same way if so requested.

The differences in basic electricity production cost methodologies mentioned so far are important examples of how studies computing production costs may differ. Some studies use simple formulas, others complex models. In some cases only cost figures and assumptions are presented but not the methodology itself. However, several other differences and issues with respect to production costs methodologies can be mentioned.

A notable example is the assumption on discount rates, a key factor in determining electricity production costs (see Eq. (1)). Discounting is used to determine the present value of a stream of future cash flows and it has a significant impact on electricity production costs, since the choice of the discount rate is one of the major cost factors for capital-intensive power generating technologies. In this regard, the reviewed studies differ considerably in their discount rate assumptions, making the stated cost figures not only difficult to compare, but also to generalize as the presented production costs are dependent on the used discount rate.

Other areas where studies tend to differ include different assumptions for the power plant economic life, the inclusion of decommissioning and refurbishment expenses, the assumptions on residual values, and for the inclusion of flue gas treatment and ash management costs. Regional conditions seem to explain some of the differences in the reported cost figures, meaning that it will be difficult to compare or use costs originating in foreign studies. A key observation by IEA and NEA [5] is that country-specific circumstances, such as market conditions and availability of resources, are among the main determinants when computing electricity production costs.

Time and economy-of-scale are other important factors influencing production costs. The IHS CERA Power Capital Cost Indexes have shown considerable increases in both European and North American power-plant capital costs since the year 2000 (Fig. 6). They also reveal that cost changes tend to occur rapidly in time. Similar observations can be found in Elforsk [8], showing a compilation of some Swedish and international indexes related to power-plant capital cost increases: all indexes point to significant cost increases during the years 2000–2010. When it comes to production costs, significant cost changes (both positive and negative) are observed in updated studies, such as those in Elforsk [8,31], and in the latest DECC studies [10,12,32]. A strong influence of economies of scale, meaning that production costs are also significantly affected by the installed capacity, i.e. plant size, was highlighted in Elforsk [8] and many other reviewed studies.

The methodological differences and the different assumptions create an evident risk of comparing "*apples with oranges*" when considering the electricity production costs of the different studies. Since all cost factors cannot be discussed in this review, the focus below will be placed on some elements that exhibit significant impact on the stated production costs.

3.2. Investment costs

Investment costs include overnight investment costs (see Fig. 7), which is the cost incurred for building a power plant immediately, i.e. "overnight". It does not include any assumptions on interest expenses that occur during the construction period. Overnight investment costs are often accompanied by assumptions on "interest during construction" (IDC) expenses. Examples where studies differ include the assumptions on overnight cost increases due to first-of-a-kind problems, on green field or brown field conditions, and on inclusion of grid-connection costs. For example, *first-of-a-kind* projects are often associated with higher costs than latter projects due to missing learning effects, i.e. they cannot benefit from lessons already made. A green field project is constructed on undeveloped land, whereas brown field alternatives are built on abandoned industrial sites ready for re-use.

The overnight cost components are difficult to identify due to lack of transparency, making it difficult to distinguish where studies differ specifically and why they present such different investment cost figures.

The most common way of accounting for the total investment costs is to add the assumed interest expenses (occurring during the construction period) to the assumed overnight investment cost. Interest expenses are dependent on construction period, construction period interest rate, cost outlay, and overnight cost, which all differ depending on the study examined (see [29] for details). Such differences might have a non-negligible impact on production costs, especially when considering technologies associated with long construction times and high capital costs.

[4] We remark that it is not electricity which is discounted in the denominator in Eq. (1), but rather the value of the output that is produced.

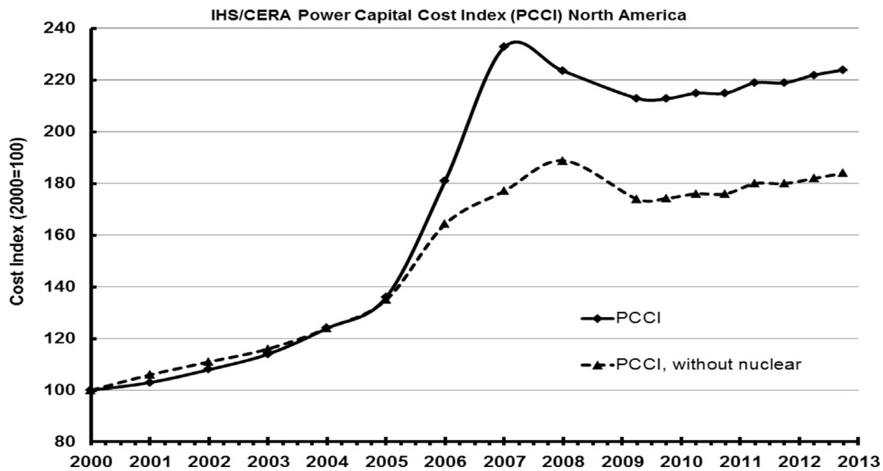


Fig. 6. Time evolution of the Power Capital Cost Index (PCCI) for North America. This index tracks the costs associated with the construction of a portfolio of 30 different power generation plants in North America.
Data source: IHS [33].

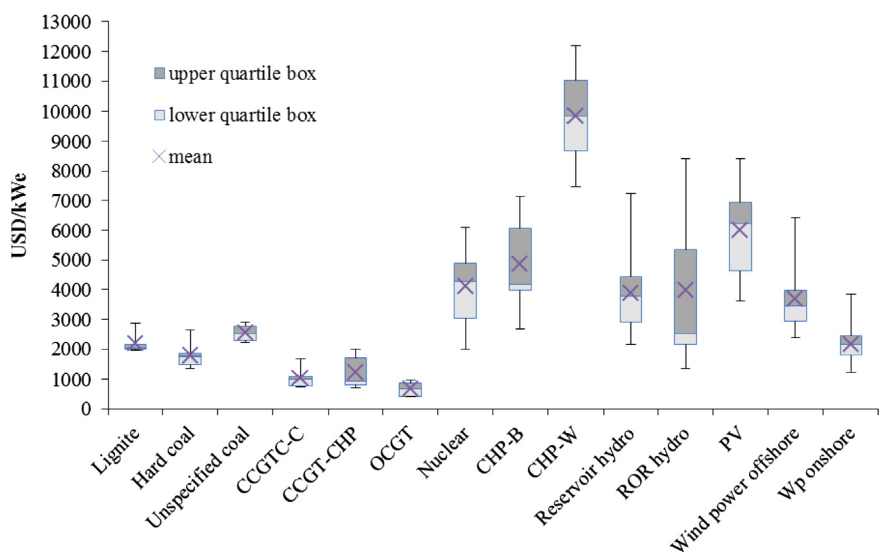


Fig. 7. Overnight investment costs presented in the reviewed studies (i.e. [4,5,7,8,10–15,20,36]). The cost figures are visualized in box plots showing the minimum value, lower quartile, median, upper quartile, and the highest value. The mean value is also included in the figure. Observe that the presented overnight investment costs are expressed per unit of installed capacity; whereas other cost factors are expressed per unit of electricity produced, i.e. levelized costs.

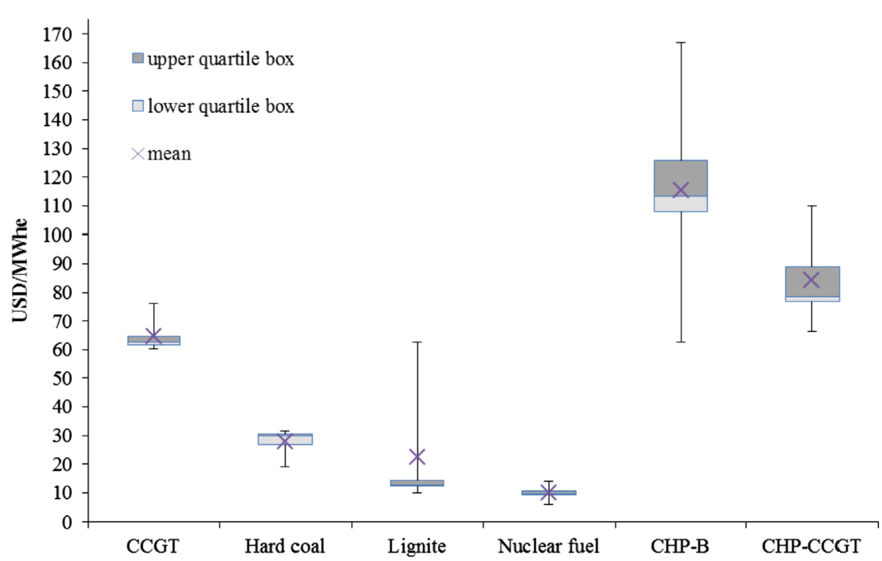


Fig. 8. Levelised fuel costs presented in the reviewed studies (i.e. [4,5,7,8,10,12,14]). The cost figures are visualized in box plots showing the minimum value, lower quartile, median, upper quartile, and the highest value. The mean value is also included in the figure. Note that CHP-W fuel costs are omitted, since the costs tend to be negative due to gate fees. Reported fuel cost figures for CHP-W is in the range between −98 USD/MWhe and −246 USD/MWhe.

Some studies [7,13] do not mention the IDC costs. This is an issue, since if the IDC costs are not included; the cost difference between overnight and total investment costs (including IDC construction costs) might be substantial.

One explanation for the wide range of estimates reported for the overnight investment costs of CHP-B, PV, and hydropower is economies of scale, where the overnight investment cost per installed unit of installed capacity is generally smaller for plants with larger power output. Moreover, investment costs for hydropower plants also tend to be highly site specific [34]. Similar observations can be made for PV, where the type of application, e.g. rooftop versus open-air installation, is a major cost factor [20].

3.3. Fuel and O&M costs

Fuel costs are heavily affected by the assumptions on the fuel price and plant efficiency and they both have to be considered when looking at the presented fuel cost figures (see Fig. 8).

Fuel prices are treated quite differently in the reviewed studies. IEA and NEA [5] and Elforsk [8] assume fuel prices to be constant in time. CASES [14], EUSUSTEL [35] and NEEDS [4] assume increasing prices for some fuels, and oscillating or constant prices for others. DECC [36] and EIA [37] also seem to assume oscillating fuel prices, but actual data can only be found for fossil fuels. The approach used by VGB [7] is unknown, since no fuel price data or other information is provided in their report. Large differences also exist when it comes to the assumed absolute numbers, and in case of CHP-B power plants, also for the choice of the fuel used. Fuel costs for CHP-W plants are negative, since such stations are granted so called "*gate fees*" for accepting and processing waste from other parties. Gate fees tend to be site- or country-specific and they are crucial to CHP-W electricity production costs.

Assumed power plant efficiencies also affect total fuel costs. A lower electrical efficiency leads to more fuel being spent per unit of electricity produced. The total thermal efficiency of a CHP plant is also very important, as it affects the amount of produced heat. For some power generating technologies, the assumed efficiency figures can be quite different (see Table 4). It is much more difficult to evaluate the reported O&M costs, mostly due to the lack of transparency in the reviewed studies. However, it is important to be aware of the large range of estimates reported for some of the power generating technologies (see Fig. 9). Note that EUSUSTEL [15] reports unusually high O&M costs for hydropower, but the reason for such diverging figures from the average estimates is not discussed.

Table 4
Reported power-plant efficiencies. Electrical efficiency is defined as the ratio between useful electricity output at a specific time, and the energy value of the supplied energy source during the same time period. The thermal efficiency is the ratio between total energy output, i.e. electricity and heat, and the heat-content of the consumed fuel. Note that the stated efficiency figures over 100% for some CHP plants is due to assumptions on flue-gas condensation, making it possible to utilize otherwise lost heat. Such heat energy is excluded when using assumptions on fuel energy content, based on lower heating values. EIA figures are not included because they use higher heating values, making their stated plant efficiencies not comparable with the other studies.

Technology	Electrical efficiency [%]	Thermal efficiency [%]
Hard coal	45.0–48.0	
Lignite	40.0–45.5	
CCGT-C	55.0–60.0	
OCGT	38.0–45.0	
Nuclear	33.0–36.0	
CCGT-CHP	45.0–50.5	89.0–92.0
CHP-B	18.5–30.9	65.0–108.0
CHP-W	19.2–19.4	99.0

3.4. Heat crediting in combined heat and power plants

Combined heat and power plants (CHP) produce both electrical energy and heat energy. Costs borne by a CHP plant could therefore be imputed to both the produced electricity and to the produced heat. A generally accepted methodology in all of the reviewed studies is to modify the CHP electricity production costs by subtracting an assumed value for the heat energy produced, called *heat credit*.

CASES [14] assumes that the produced heat replaces heat output from an alternative natural gas boiler plant. The heat credit should therefore be equivalent to the cost of fuel that otherwise would have been spent in the gas boiler. Elforsk [8] uses multiple heat credit assumptions and states that regardless of the site-specific situation, a heat credit equivalent to variable district heating costs can always be motivated. Such heat credits are computed on the basis of the cost of fuel usage, as well as variable O&M costs in an alternative biomass-fired boiler plant. Fixed heat

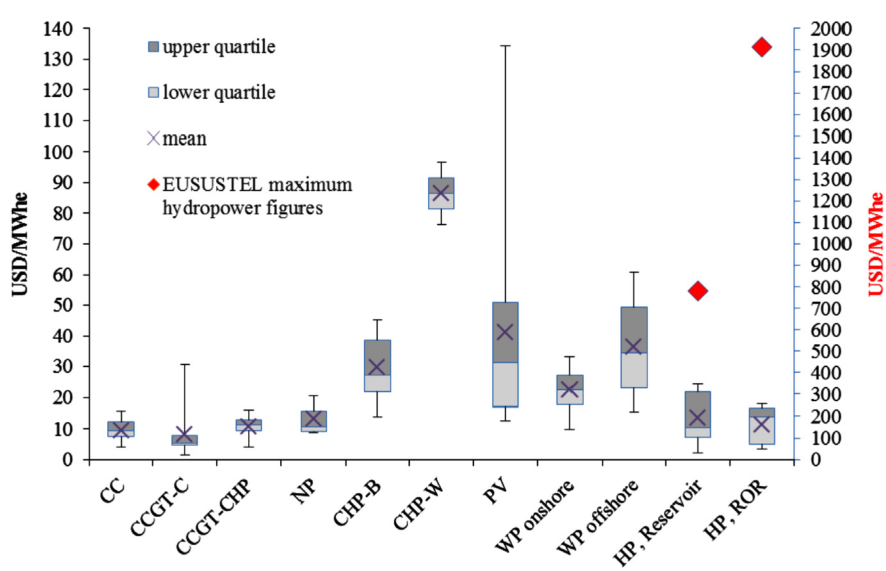


Fig. 9. Presented O&M costs in the reviewed studies (i.e. [4,5,7,8,10–15,18]). Note that two *y*-axis scales are used, where the second rightmost one is used to visualize the stated maximum EUSUSTEL hydropower figures.

credits based on fixed O&M costs and the investment cost for an alternative heat-only boiler plant are also used in the study.

DECC (see [10] for details) bases its heat credits on avoided gas boiler costs. However, lack of transparency makes it difficult to understand its methodological approach. Avoided capital and O&M costs are based on a heat incentive by DECC [36]; whereas avoided fuel and carbon dioxide emission costs are based on DECC gas and carbon price projections. However, the heat incentive actually seems to be a fixed tariff rate [38], and where electricity production costs are presented, like in Arup [10], heat revenues appear as a fixed negative operating cost. This makes it difficult to understand how heat credits actually are accounted for.

IEA and NEA [5] use a very simple approach, assuming a fixed heat credit per MWh of heat energy produced. EUSUSTEL does not mention the issue of heat credits in their main technical report [15]. However, heat credits appear in their cost calculation appendixes [39,40], but without a reference or explanation.

It is evident that various studies treat heat credits quite differently. A great deal of caution is therefore recommended when looking at CHP production cost figures. The proportion of heat energy production in CHP plants tends to increase with lower plant electrical efficiency, which raises the significance of heat credits [5].

3.5. Assumed electrical energy production

One factor that is extremely important for the estimations of production cost is the amount of electricity that is assumed to be produced, since the costs are generally expressed per kWh of produced electricity. This means that, for instance, a doubling of assumed production will cut the cost per kWh in half.

The capacity factor is a common way of theoretically describing the output of a power plant by expressing the assumed production as a fraction of the rated power during a certain period of time. It is defined as the ratio of actual energy produced to the theoretical maximum of running constantly at the installed power capacity. It should be added that the capacity factor does not express when in time the electricity is produced, but only the fraction of the theoretically maximum production that is actually produced, or assumed to be produced.

Power generating technologies such as nuclear, coal and CCGT are mostly assumed to run in baseload[5] mode with capacity factors close to 0.85 (see Table 5). However, for both coal and CCGT, the span is quite large. OCGT is treated differently with capacity factors ranging from 0.18 to 0.86, implying that it covers the entire operating span, from pure peak load to base load operation.

An interesting observation can be made for CHP technologies (Tables 5 and 6). While most of the studies assume capacity factors high enough to imply year-round operation, Elforsk [8] assumes that a CHP plant operates during the heating season only. Therefore, its assumed capacity factor is significantly lower than those reported in the other reviewed studies. An exception is made for CHP-W, because such stations have to be used in baseload operation due to the high investment costs and demand all year-round for accepting waste. The reason why other studies assume all year-round CHP operation is unknown.

The different assumptions on capacity factors presented in this section are high enough to cause notable differences in estimated production cost. Moreover, production costs are also more sensitive to incremental changes in the assumed capacity factor. An assumed capacity factor of 0.3 versus 0.2, has a significantly larger impact on production costs compared to that of 0.9 versus 0.8 (see [29] for details). Capacity factors for intermittent technologies also tend to be highly site-specific, why expressing production costs of electricity as one fixed number for such technologies is questionable.

Table 5
Assumed capacity factors for non-renewable power generating technologies.

Study	Capacity factor				
	NP	CC	CCGT-C	CCGT-CHP	OCGT
IEA and NEA [5], min	0.85	0.85	0.85	0.85	–
IEA and NEA [5], max	0.85	0.85	0.85	0.85	–
IEA and NEA [5], med	0.85	0.85	0.85	–	–
CASES [14]	0.86	0.86	0.86	0.86	0.86
EUSUSTEL [15]	0.90	0.85	0.90	0.85	–
Elforsk [8]	0.87	0.78	0.78	0.56	–
SKGS [13]	0.90	–	–	–	–
DECC [9]	0.87	0.95	0.93	0.93	0.18
EWEA [18]	–	–	–	–	–
NEEDS [4]	0.84	–	0.82	–	0.57
EIA [11]	0.90	0.85	0.87	–	0.30
VGB [7]	0.90	0.86	0.68	–	0.68

3.6. Carbon dioxide emission costs

Some studies account for carbon dioxide emission fees which penalize fossil-fueled power plants. Such costs could be seen as external costs, but some studies choose to internalize direct carbon dioxide emission costs, i.e. emissions occurring during power plant operation, into presented electricity production costs, why we opted to keep them in this paper. Discrepancies in the reported levelized carbon dioxide emission costs are due not only to different assumptions for carbon dioxide emission fees (Table 7), but also to the assumed power plant efficiencies (Table 4) and to the fuel carbon content. However, none of the reviewed studies provide any information about the relative fuel carbon content and how they calculate the carbon dioxide emissions. It is therefore difficult to completely understand how these studies arrive at such different results.

It is important to be aware of whether or not the carbon dioxide emission costs have been included, as they might have a significant impact on the electricity production costs (see Table 8). For instance, the CO_2 emission costs for hard coal used by DECC [12] is high enough to completely change the picture of production costs for coal power compared to other electricity generating technologies.

3.7. Backup costs for intermittent technologies

Some studies (i.e. [14,15,41]) argue that intermittent, non-dispatchable, power generating technologies should include the backup costs due to their fluctuating electrical energy production. Backup power is seen as a necessity because of the inflexible, variable and also unpredictable behavior of the intermittent technologies. Backup costs should be seen as external costs, as they are shared amongst all producers, and hence society, and not directly accounted for by individual producers. We opted to keep them as some studies internalize them into stated electricity production costs.

EUSUSTEL accounts for backup costs in their cost calculation appendixes [39,40] but data and information cannot be found in the main reports [15,35]. Another transparency issue is that neither EUSUSTEL nor NEEDS describe the methodology used for calculating the backup costs. This makes it impossible to exactly deduce how backup costs are accounted for. Interestingly enough, EUSUSTEL also seems to assume that large-scale reservoir

[5] Baseload power plants meet a region's continuous energy demand. They typically run at all times except in the case of repairs or scheduled maintenance. Peaking power plants usually run when there is a peak in demand for electricity, e.g. during evening hours when household appliances are heavily used, or during cold winter days and hot summer days.

Table 6
Assumed capacity factors for renewable power-generating technologies.

Study	Capacity factor						
	HP, Reservoir	HP, ROR	CHP-B	CHP-W	WP on	WP off	PV
IEA and NEA [5], min	–	–	–	–	0.25	0.37	0.10
IEA and NEA [5], max	–	–	–	–	0.23	0.37	0.23
IEA and NEA [5], med	–	–	–	–	0.26	–	0.13
CASES [14]	0.34	0.57	0.86	–	0.30	0.46	0.12
EUSUSTEL [15]	0.80–0.91	0.57–0.8	–	–	0.23–0.29	0.29–0.5	0.15
Elforsk [8]	0.46	–	0.55	0.76	0.3–0.35	0.34–0.35	0.12
SKGS [13]	0.46	–	–	–	0.26	–	–
DECC [9]	0.46	–	0.77	0.83	0.25–0.29	0.38	0.11
EWEA [18]	–	–	–	–	0.17–0.33	0.41–0.42	–
NEEDS [4]	–	–	0.91	–	–	0.46	–
EIA [11]	0.52	–	–	–	0.34	0.34	0.25
VGB [7]	–	0.80	–	–	0.21	0.37–0.43	0.23

Table 7
Assumed carbon-dioxide emission fees in the reviewed studies – if reported – [USD/metric ton CO_2].

Study	Fee
VGB [7]	41.8
DECC [9]	21.9
IEA and NEA [5]	31.2
EUSUSTEL [15]	15.3

Table 8
Reported levelised carbon-dioxide emission costs [USD/MWh$_e$].

Study	CC hard coal	CC lignite	CCGT-C	CCGT-CHP	OCGT
VGB [7]	37.6	39.0	19.4	–	22.2
DECC [9]	78.1	–	29.6	–	–
IEA and NEA [5], median case	24.9	–	10.9	–	–
IEA and NEA [5], min	22.9	26.2	10.6	9.4	–
IEA and NEA [5], max	24.5	28.3	11.7	15.5	–
EUSUSTEL [15]	10.6	13.6	5.2–5.6	–	–

$$C_{BU} = \frac{A_k}{h_v} - \frac{A_k \cdot P}{h_w} = A_k \cdot \left(\frac{1}{h_F} - \frac{P}{h_W}\right)$$

C_{BU} = Cost Back-Up
h_v = Full loading hours, supply
h_w = Full loading hours of the renewable power plant
P = Power credit of the renewable energy plant
A_k = Annuity, incl. the annual fixed costs for the Back-Up technology

Fig. 10. Backup cost formula as used by CASES [42].

hydropower should be subjected to backup costs [39,40], but no justification for this assumption is provided.

Backup power is assumed by CASES [14] to be delivered by either a hard coal or a CCGT power plant, and the same assumptions are made in the EUSUSTEL and the NEEDS studies. Fig. 10 shows the backup cost formula used by CASES [14].

Even though CASES provides the formula used, it is still difficult to understand exactly how the backup costs are calculated. No calculation examples are provided and the terms included in the backup cost equation (Fig. 10) are not properly explained. For example, it is unclear which type of annuity is used; the annuity-due or the annuity-immediate, and the inputs required for its computation are not provided.

The issue of backup costs introduces a great amount of uncertainty, both with regard to their computation and whether they should be accounted for or not. It is also questionable if they should be internalized into the electricity production costs as they are likely not paid for by individual producers. However, backup costs and other electricity system cost factors (see chapter 4) are perhaps as important in decision and policy making as other external cost factors, so that they should be included when discussing total electricity generation costs. The assumptions about such costs are by no means negligible. The inclusion of backup costs for wind power causes production costs to increase by 15–50% in reviewed studies, depending on the backup technology assumed (see [29] for details). As such, backup costs can constitute a major part of total wind power electricity production costs, thereby complicating the comparison with production costs presented in other studies. Please note that other intermittent power sources, such as photovoltaics, also are in need of backup power and are subject to backup costs.

3.8. Issues related to transparency and input data

A general problem with the reviewed studies is the lack of transparency, making it difficult to understand and analyze the different steps in computing the electricity production costs. This is also the main reason why it is difficult to address the impact of certain factors on the reported results. Lack of transparency includes confidential data sources and models, poorly explained formulas, lack of concrete calculation examples, and unknown or unexplained assumptions and approaches. These points complicate the understanding of the methodology used in the cost calculations, thereby causing credibility and suitability concerns.

When analyzing the presented cost figures, for example investment costs and O&M costs, these are generally presented as a single figure, meaning that the individual components are not specified. Thus, it is difficult to assess where costs differ and the reasons for discrepancies between studies. In most cases, it is unknown whether the presented costs are based on existing power plants, power plants under construction, planned projects, literature data, or something else, since this information is rarely specified in the reviewed studies.

Another issue is that some studies tend not to differentiate between power generating technologies with similar, but not equal, technical characteristics. For example, different kinds of solar generating technologies such as crystalline silicon and thin-film solar cells are commonly grouped together and named "*photovoltaics*" and nuclear power are for some of the studies referred to as "*PWR*", even though some alternative reactor technologies such as BWR are used. What kind of power plant is actually being assessed can be defined quite differently. The actual

power plant referred to can be a single wind turbine or a large wind farm, pulverized coal combustion or advanced pulverized coal combustion, or sometimes not specified at all. Some studies define technical characteristics quite specifically, while in others they are not given much attention. Cost and technical input data are also frequently decoupled, meaning that such data are collected from different sources and no direct resemblance exists. In many cases it is difficult to verify whether the reviewed studies mix different, but similar, power generating technologies (such as different types of photovoltaic technologies, for example) into a common category (such as "*photovoltaics*"). Moreover, the lack of transparency makes it difficult to assess whether generalizing technologies or decoupling data sources have any significant impact on the presented electricity production costs.

4. Policy implications

The levelized cost of electricity, or similar definitions (see the previous discussion in Section 3), has become the most popular methodology for comparing electricity production costs from different technologies. The methodology is focused on the producers, but what about the total costs that have to be paid by the consumers or society?

Production costs are in most cases limited to the plant-level, meaning that the system border is placed where electrical energy is fed to the grid.[6] This implies that the current levelised cost methodologies do not focus on a power plant's different impacts on the electricity system as a whole. As pointed out earlier in this paper, some studies account for backup cost of intermittent power sources (Section 3.7) and grid connections costs (Section 3.2). However, while grid connection costs are based on standard values which are common for most power generating technologies, other factors such as costs for providing reserve power and long distance transmission investment costs are not considered.

Current energy policies for electricity generation aim, among other things, to increase renewable electrical energy production, diversify production to improve energy security, and reduce carbon dioxide emissions due to electricity generation [43]. However, it is important that such policy measures are implemented on a cost-effective basis, because there might be other, more cost-effective ways of reaching the specified targets. While the views on how much more costs would be added to the total production costs can be rather different, there is widespread agreement that cost increases would be more substantial for intermittent, non-dispatchable, power sources ([5,44,45]). Table 9 shows a compilation of some reported estimates for system integration costs for wind power.[7]

The fact that current levelised cost methodologies do not incorporate electricity system costs in a consistent way needs consideration if the presented production costs are to be used for planning and policy making. Integration costs of intermittent power sources should not be considered as ways of discriminating such technologies. Instead, they should be considered as costs based on inherent technical aspects to be considered when evaluating electricity generation costs; much like when evaluating emission-related external costs of fossil-fueled power plants. Moreover, integration of renewable power sources can bring about benefits, such as fossil fuel displacement savings. These assessments were not considered in this review.

In general, the choice of the system boundary might have a significant impact on the electricity generation costs, both for fossil-fueled and for renewable power generating technologies: aside from costs due to integration of intermittent power sources and to external effects, other factors such as costs for R&D, government subsidies and taxes might also be added to the production costs even though they are commonly neglected. Taxes and subsidies vary from country to country and costs are therefore country specific. However, some of the reviewed studies tried to measure the effect of taxes in the form of fees on carbon dioxide emissions (see section 3.6). Such an approach is not wrong, but neglects other indirect cost factors and imposes different system boundaries for different power generating technologies. For example, it is quite strange why changes of costs due to renewable power subsidies are not included, while carbon dioxide penalties are sometimes accounted for. Studies are generally poor in communicating the impact of choosing different system boundaries and in explaining the limitations of their computed results. This is a transparency issue that has to be considered.

There are, however, other aspects, beyond a missing system perspective, which have to be considered for policy making. Inclusion of carbon dioxide emission costs can seriously affect the generation costs of fossil-fueled power generating technologies (Section 3.5) and might therefore have to be considered for new investments in fossil-fueled generation. Moreover, methodologies computing external costs arising from the power plant impact on human health, climate change, and other environmental issues have not been reviewed in this paper. Nevertheless, these costs have been examined by some of the reviewed studies (as well as other papers), which found out considerable electricity generation cost increases for fossil- and biomass-fueled power generating technologies (see Table 10). Inclusion of external costs can therefore have a significant impact on policy and decision making.

From a producer's perspective, the levelised-cost-of-electricity approaches fail to account for an important aspect related to economic value: some power generating technologies are more likely to produce electricity during those hours of the year when the electricity price reaches high values. Dispatchable power generating technologies are able to follow peaks in electricity price, whereas non-dispatchable alternatives only produce electrical energy during favorable meteorological conditions. This implies that the net economic value of projects with the same levelised cost may vary substantially depending on their production profiles and the associated market value of the electricity they provide [44]. It also implies that technologies subject to high levelised production cost figures might be more attractive than other lower-cost alternatives, due to better economical competiveness. Together with the issue of missing integration costs for intermittent power sources, this means that current levelised cost of electricity assessments do not differentiate between power and energy, a fundamental difference between dispatchable and non-dispatchable generation sources.[8] When considering energy policies, such aspects have also to be taken into account. Current levelised costs of electricity approaches neglect these issues.

Therefore, the habit of generalizing electricity production cost figures is questionable to say the least: cost escalations tend to occur rapidly with time, the impact of economies of scale is significant, costs are in many cases site-specific, and country-specific circumstances affect production costs. In addition to this, assumptions on the cost-influencing factors such as discount rates, fuel prices and heat credits fluctuate considerably and have

[6] By "*system border*" we mean a boundary that separates the internal components of the power plant from external entities, which are excluded from the scope of the study.

[7] The studies presenting these estimates were not thoroughly reviewed with respect to the used methodologies and the underlying assumptions; the estimates presented here are reported only to show some quantitative assessments for system integration costs, as well as the large dispersion that characterizes these estimates.

[8] Energy is the capacity of a system to perform work. Power, however, is the rate at which work is performed. As such, energy is consumed over a period of time whereas power is instantly consumed.

Table 9
System integration cost estimates for wind power. It was sometimes difficult to assess which type of integration costs was considered, due to the different naming conventions and lack of transparency.

Study	Considered cost factors	Cost [USD/MWhe]
Albadi et al. [46]	Regulation, load-following capacity, unit commitment	2.0–5.8
IEA and NEA [5]	Balancing	0–5.9
Mills et al. [47]	Transmission	15.1–79.1
MIT Energy Initiative [46]	Regulation, load-following capacity, ancillary services	5.0–20.0
Williams [48]	Balancing, planning reserve, transmission	32.4

Table 10
External cost estimates [USD/MWhe]. Epstein et al. [49] focus on external costs related to coal generation and presents a best estimate together with the total external cost span. Kitson et al. [43] use three different categories: fossil fuels, nuclear and renewables. NEEDS [50] present two different estimates: one for the case of low climate change damage costs and the other for high climate change damage costs.

Study	Hard Coal	Lignite	CCGT	CCGT-CHP	NP	CHP-B	HP	PV	WP
CASES [42]	48	31	21	20–21	3	10–31	0–1	13	1
Epstein et al. [49]	178, 94–269		–	–	–	–	–	–	–
EUSUSTEL [15]	16.4	22	7	–	1	–	0	1	0
Kitson et al. [43]	7–238				2–12	2–32			
NEEDS [50]	32–169	26–168	12–80	–	2–3	43–62	–	9–19	1–2

Table 11
Range for the estimates of electricity production costs across the reviewed studies, using a 5% discount rate [USD/MWh$_e$] together with the lower and upper quartiles. The second column presents the entire production cost range, while the third column contains the 25% and 75% quartiles, i.e. the interquartile range.

Technology	Total range	25–75%
Lignite	39–97	40–41
Hard coal	45–119	47–55
CCGTC-C	71–98	81–89
CCGT-CHP	61–154	80–117
CCGT-CHP+HC	32–119	46–86
Nuclear	37–81	44–61
WP onshore	54–169	71–89
WP offshore	61–196	97–131
CHP-B	167–284	181–234
CHP-B+HC	17–173	55–128
Reservoir hydro	50–810	64–417
ROR hydro	51–1942	91–577
PV	126–773	285–616

Table 12
Range for the estimates of electricity production costs across the reviewed studies, using a 10% discount rate [USD/MWh$_e$] together with the lower and upper quartiles.

Technology	Total range	25–75%
Lignite	46–119	54–73
Hard coal	54–80	60–69
CCGTC-C	77–109	90–97
CCGT-CHP	66–176	86–133
CCGT-CHP+HC	37–140	51–103
Nuclear	54–142	63–105
WP onshore	74–244	115–148
WP offshore	85–271	159–199
CHP-B	175–357	205–290
CHP-B+HC	34–240	85–218
Reservoir hydro	94–846	116–377
ROR hydro	42–1964	61–220
PV	198–1061	272–761

a significant impact on production cost results. Presenting generalized production cost figures is therefore an oversimplification of the reality and cannot be recommended.

Tables 11 and 12 give the range for the cost estimates for the reviewed studies, and they show why generalization of production costs is a bad idea. For some power generating technologies such as hard coal and CCGT the dispersion is relatively small, but for many other technologies, the relative difference between the lowest and highest values can be extremely large, like for ROR hydropower, whose estimates range between 51 and 1942 USD/MWhe. In these situations, it is better to focus on the interquartile range (i.e. between the 25% and 75% quartiles) which removes the impact of extreme values and is likely more robust. For example, it can be noted that the large dispersion for hydropower is mainly due to the significant O&M costs stated in the EUSUSTEL (2007d) [15] study.

Electricity production cost estimates can, for instance, be used as ways of estimating necessary levels of subsidies or taxes to make "*clean*" energy competitive with fossil fuels. However, other factors such as external costs related to environmental/hazardous emission impacts and electricity system integration costs also need a great deal of consideration in policy making. Such costs should be internalized to the production costs if different power generating technologies are to be compared on equal terms. If not, policy-related targets such as reducing carbon dioxide emissions, increasing renewable power generation and increasing energy security might occur in non-cost-effective ways. However, given the wide range of production cost estimates, computing or estimating necessary levels of taxes or subsidies is clearly not an easy task.

5. Conclusions

Twelve recent studies on electricity production costs for power generating technologies were reviewed, showing a wide range in cost estimates for producers. The analysis highlights significant methodological differences and different assumptions. This makes the presented cost figures rarely comparable with each other and unsuitable for generalization as representative of electricity production costs for entire power generating technologies.

Circumstances may vary from study to study and there might be good and justified reasons as to why these studies choose different assumptions and approaches. Nevertheless such differences have to be kept in mind as they affect the results. In general, policy makers are likely unaware of the significant impact of using different approaches and assumptions for electricity production

cost assessments. In this regard, using sensitivity analyses may be of help to visualize the possible range of final production costs.

From a policy making point of view, electricity production cost assessments have to be more open and transparent, and should present the range of validity of their results and in which contexts they can be used. Current levelised cost of electricity methodologies focus mainly on the costs of electricity production. Additional assessments of external costs and costs related to the impact on the whole electricity system have to be included if these results are to be used for the planning of sustainable electricity systems. Hence current electricity production cost methodologies are unable to account for the socioeconomic aspects related to power production and the results of the assessments should therefore be taken with caution.

From a system perspective, current electricity production cost methodologies are also unable to account for the different abilities of power plants to deliver power when needed, a key issue considering the increasing share of intermittent power sources in the electricity system. For this reason, electricity production cost methodologies need to assess the difference between power and energy. Power-generating technologies can only be compared on equal terms provided knowledge is available on how the mode of operation of the power sources; constant, intermittent, or regulating power. Other limitations are inappropriate costs generalization, sensitivity studies which are ignored or poorly communicated, and the choice of different system boundaries which is not considered when instead it should, given its potential large impact on presented costs.

Electricity production costs are country specific and sensitive to power plant location. Country specific circumstances have a big impact on presented results, which highlight the need to look at electricity production costs at the country level. Moreover, costs tend to be site-specific and sensitive to changes in input parameters. Furthermore, costs change rapidly with time and assumptions on the cost-influencing factors such as discount rates, fuel prices and heat credits fluctuate considerably and have a significant impact on production cost results. Therefore, generalizing electricity production costs to represent entire specific technologies is not recommended.

Electricity production costs assessments similar to the studies reviewed in this work disregard many important cost factors, making them potentially inadequate for decision and policy making, and should only be used to provide rough ballpark estimates with respect to a given system boundary. Caution is therefore highly recommended when referring to electricity production cost assessments.

Acknowledgments

This study has been supported by the STandUP for Energy collaboration initiative.

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